BEFORE
THE PUBLIC SERVICE COMMISSION
OF SOUTH CAROLINA
DOCKET NO. 2019-226-E

IN RE: South Carolina Energy Freedom Act (House Bill 3659) Proceeding Related to S.C. Code Ann. Section 58-37-40 and Integrated Resource Plans for Dominion Energy South Carolina, Incorporated	))))))))	**DIRECT TESTIMONY OF KENNETH SERCY ON BEHALF OF THE SOUTH CAROLINA SOLAR BUSINESS ALLIANCE, INC.**

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

My name is Kenneth Sercy. I am an independent electric sector consultant, and my business address is 9042 East 24th Place #102, Denver CO 80238.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

I have a Bachelor of Science degree from Clemson University and a Master of Environmental Management degree from Duke University, and ten years of experience in electricity markets, policy, and regulation focused on engineering-economic modeling and cost-of-service ratemaking. I have designed, run, and evaluated a variety of electric power modeling analyses including production cost, capacity expansion, and avoided cost and related cost-effectiveness tests, and have evaluated cost recovery, resource planning, asset certification, program and tariff design in more than sixty regulated utility proceedings, primarily in South Carolina. While studying at Duke University, I worked for two years at the Nicholas Institute for Environmental Policy Solutions supporting energy modeling research using the US Department of Energy's NEMS model. After graduating from Duke in 2012, I served as the SC Coastal Conservation League's Utility Regulation Specialist for five years, where I managed the organization's work before the SC Public Service Commission and supported a variety of electric sector policy objectives. I have co-authored technical papers published by Clemson University's Strom Thurmond Institute, the North Carolina Sustainable Energy Association, and the journal *Energy Policy*. A copy of my *curriculum vitae* is included as Exhibit A.

Q. HAVE YOU PREVIOUSLY PROVIDED TESTIMONY TO THIS COMMISSION?

No, I have not.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

My testimony reviews Dominion Energy South Carolina's 2020 integrated resource plan, with a focus on compliance with Act 62 and adherence to industry best practices for long-term resource planning. I identify numerous flaws in the development of the Company's IRP and make recommendations for correcting those flaws to ensure the 2020 IRP identifies the most reasonable and prudent plan for meeting DESC's customer demand moving forward. I also make recommendations for improving the Company's planning process in future years.

Q. PLEASE PROVIDE A BRIEF SUMMARY OF YOUR CONCLUSIONS AND RECOMMENDATIONS.

This proceeding is the first to occur under the overhauled integrated resource planning requirements of Act 62. Those requirements cover several major structural elements of long-term resource planning in order to ensure that electric utility investment and procurement decisions lead to positive outcomes for South Carolina residents and businesses. DESC's 2020 IRP falls far short of the bar set by Act 62 in multiple major areas, including identifying options for meeting demand, fairly evaluating those options under a range of possible future circumstances, and selecting a prudent long-term plan that balances several statutory objectives. My testimony recommends many improvements in these areas that should be applied to DESC's future IRPs, along with a targeted plan to revise the Company's 2020 analysis that would reasonably cure the 2020 IRP's deficiencies within statutory time constraints. My recommendations create a level playing field where all viable energy resources, including clean energy options such as solar and battery storage, are able to compete. A revised 2020 analysis could demonstrate that the most reasonable and prudent means of meeting customer demand on DESC's system includes taking steps toward a more diversified, cleaner energy mix. Taking those steps would align with South Carolina energy policy, make progress towards achieving Dominion Energy's corporate sustainability commitments, and continue to grow the state's clean energy sector at a time when major investments and job creation would carry an outsized benefit for South Carolinians.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

My testimony is organized as follows:

I. Background on IRP and Act 62

II. Candidate Resource Plans

III. Scenario Analysis

IV. Selecting the Preferred Resource Plan

V. System Flexibility

VI. Conclusions and Recommendations

I. BACKGROUND ON IRP AND ACT 62

Q. WHAT IS INTEGRATED RESOURCE PLANNING?

Integrated Resource Planning ("IRP"[1]) is a structured, transparent process for comparing options to meet electric demand. It was introduced in the electric sector in the 1980s, has been widely adopted across the US, and continues to play a key role today in most states.[2] This includes some states that initially turned away from IRP in connection with electric industry restructuring and later re-adopted it.[3] That's because IRP serves a unique and vital purpose within utility regulation, and has also proven highly adaptable to changing industry conditions as well as local jurisdictional issues.[4] IRP provides a way to comprehensively and systematically consider the wide array of factors that impact electric system choices. When implemented prudently, IRP can save ratepayers billions of dollars, help regulators understand risk exposure and make decisions that align with their risk preferences, improve environmental outcomes, and facilitate stakeholder buy-in for utility plans, reducing the risk of future cost recovery disallowance.[5] It is a powerful tool within the regulatory toolbox, but must be implemented carefully to provide these benefits.

Q. HOW DID ACT 62 CHANGE IRP IN SOUTH CAROLINA?

Act 62 significantly strengthened the IRP process in South Carolina. Compared to the previous IRP statute, Act 62 includes an expanded and more detailed list of requirements for utility IRP filings. Act 62 also enabled formal Commission review of utility plans via a litigated proceeding, in which the Commission must ultimately accept, reject, or order modifications to the utility's proposal. These statutory changes signal both the heightened importance the South Carolina

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[1] The acronym "IRP" may refer both to the process of Integrated Resource Planning, and to the Integrated Resource Plan that is the product of that process.
[2] R. Wilson & B. Biewald. Best Practices in Electric Utility Integrated Resource Planning. Regulatory Assistance Project (2013).
[3] M. Chupka et al., Reviving Integrated Resource Planning for Electric Utilities (The Brattle Group, 2008).
[4] F. Kahrl et al., The Future of Electricity Resource Planning. Lawrence Berkeley National Laboratory (2016).
[5] Id.

General Assembly has assigned to IRP and also the critical role assigned to this Commission in reviewing and ruling on proposed utility plans.

Act 62 left intact the existing links between IRP and many other regulatory matters, and even strengthened some of these links. These include, for example, avoided cost rates, Voluntary Renewable Energy Program bill credits, value of solar calculations for customer-sited generation, community solar bill credits, grid modernization considerations, cost-effectiveness tests for energy efficiency and demand side management programs, and certification of proposed new major generating facilities.

Q. CAN YOU PROVIDE ANY ADDITIONAL CONTEXT FOR THIS PROCEEDING?

IRP was adopted in the electric sector more than 30 years ago because electric investment decisions were already difficult at the time and only becoming more challenging.[6] Yet today, most electric sector observers believe the industry is facing an unprecedented level of uncertainty, making the high-stakes decisions that typify the industry harder than ever. This uncertainty stems from a number of factors, including natural gas prices, environmental regulation, load forecast uncertainty, and the cost of a variety of technologies.[7] It is clear both from the circumstances under which Act 62 was passed and from the language of the law that the General Assembly had uncertainty and risk at front of mind when crafting this overhaul of SC's long-term planning process. Prudent implementation of Act 62 would therefore help realize the risk management objectives embodied in the law.

Another clear priority of the General Assembly, which has grown in recent years and is further affirmed by passage of Act 62, is a desire for clean energy and independent power

[6] F. Kahrl et al., The Future of Electricity Resource Planning. Lawrence Berkeley National Laboratory (2016).
[7] M. Chupka et al., Reviving Integrated Resource Planning for Electric Utilities (The Brattle Group, 2008); F. Kahrl et al., The Future of Electricity Resource Planning. Lawrence Berkeley National Laboratory (2016).

producers to be able to compete on a level playing field with traditional utility-owned generation resources when cost-effective. IRP offers a prime opportunity to fulfill this promise.

A third point of context is the accelerating trend of corporate commitments to net zero greenhouse gas emissions goals. Dominion Energy has established such a goal[8], in line with industry trends, and this long-term planning proceeding is an ideal forum in which to consider the Company's plans for achieving this goal.

And last but not least, there is national recognition that clean energy can play a large role in America's recovery from the deep economic turmoil currently gripping the nation.[9] This opportunity is as relevant in South Carolina as it is anywhere in the country. The clean energy industry has created thousands of jobs and billions of dollars in capital investment across the state, and is poised to continue growing rapidly given a fair regulatory environment.

Q. WHAT ARE THE BASIC STEPS IN IRP, AND WHAT IS THE SIGNIFICANCE OF EACH?

As commonly implemented, the IRP process involves five basic steps: (1) forecast future electricity demand; (2) identify the goals and regulatory requirements the process must meet; (3) develop a set of resource portfolios designed to achieve those goals; (4) evaluate those resource portfolios; and (5) identify a preferred resource plan.[10]

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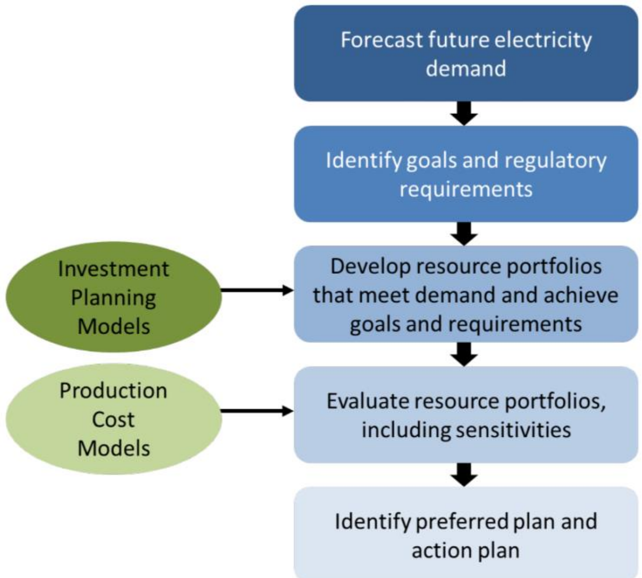
[8] DESC 2020 IRP at 26.
[9] For example, the University of California Berkeley Goldman School of Public Policy has found that scaling up clean energy deployment could add 500,000 jobs nationally relative to the business as usual case. A. Phadke et al., Plummeting Solar, Wind, and Battery Costs Can Accelerate Our Clean Energy Future (UC Berkeley, June 2020).
[10] These steps are described in a Lawrence Berkeley National Laboratory review of resource planning describes five generic steps that came to constitute IRP as its use became widespread. F. Kahrl et al., The Future of Electricity Resource Planning. Lawrence Berkeley National Laboratory (2016) at 9.

Figure 1: Generic Steps of IRP



Each of these steps has significant implications for the overall success of the IRP, and ultimately for the cost and reliability of power. For example:

- A poorly constructed set of demand forecasts could lead to too much or too little power availability, raising costs or compromising reliability;
- Failure to develop a representative set of resource plan options could overlook the best plan for customers, raising costs or exposing customers to undue risk; and
- A poorly designed cost and sensitivity analysis could create skewed cost results that mislead decision-makers about which plan is most prudent.

My testimony addresses each topic shown in Figure 1, discussing how DESC has approached these steps, and what improvements are needed to ensure that a reasonable and prudent plan is successfully identified. While I cover several major steps within IRP, I do not exhaustively review every data point or structural element of DESC's IRP. Instead, I focus on a selection of broad areas and detailed inputs that I have identified as having major implications for the ultimate conclusions of the planning process.

Q. HAVE YOU REVIEWED THE CHARLES RIVER ASSOCIATES (CRA) REPORT IN WHICH THEY REVIEW AND COMMENT ON THE DOMINION IRP?

Yes. I address a number of the report's findings and conclusions throughout my testimony. In summary, some of those conclusions are well supported and well-reasoned, and others are not. Generally, I view the CRA report as mixed in its usefulness given the inconsistency I've seen in CRA's treatment of the topics I focus on in this testimony.

Additionally, I represented the South Carolina Solar Business Alliance (SCSBA) on the call cited in the report, and note that many of the topics and specific issues that SCSBA raised as deserving attention are not covered in CRA's work product, including potential resource options excluded from DESC's process, system flexibility considerations, aeroderivative CT justification, and risk management approaches.

Q. IS THE CRA REPORT AN INDEPENDENT ASSESSMENT OF DESC'S IRP, ANALOGOUS TO THE POWER ADVISORY REPORT RELIED ON BY THE COMMISSION IN ASSESSING THE SUFFICIENCY OF DESC'S RECENT AVOIDED COST FILINGS?

No, it is not. Power Advisory was a "qualified independent third party" carefully selected by the Commission under the auspices of Act 62, whose statutory responsibility was to prepare a report "that includes the third party's independently derived conclusions as to that third party's opinion of each utility's calculation of avoided costs," used to advise the Commission in each utility's avoided cost docket.[11] Power Advisory was not selected or paid by any utility.

[11] S.C. Code Ann. § 58-41-20(I).

CRA's report was not authorized or required by Act 62. Rather, DESC (and its predecessor SCE&G) agreed in a November 2018 settlement agreement in connection with the Dominion / SCE&G merger proceedings before this Commission (Docket No. 2017-370-E) to fund "an outside consultant, selected jointly by SCE&G and ORS, to audit SCE&G's load forecast and reserve margin methodologies, review SCE&G's methodology for portfolio modeling," and submit a report to the Commission. CRA was the consultant selected for the job. I point this out not to question CRA's qualifications or integrity, but simply to note that CRA does not enjoy the same independence as Power Advisory, and that its report should be considered in that light.

II. CANDIDATE RESOURCE PLANS

Q. PLEASE PROVIDE A SYNOPSIS OF YOUR TESTIMONY REGARDING DESC'S CANDIDATE RESOURCE PLANS.

Candidate resource plans are options for meeting system electric demand over the long term. In this section, I discuss the following issues I observed regarding DESC's candidate resource plans:

1. DESC did not use common industry software to guide its candidate resource plan design.
2. DESC overlooked major categories of potential candidate resource plans, including near-term clean energy deployment and accelerated coal retirement.
3. DESC used invalid solar photovoltaic ("PV") cost and system value assumptions, and inappropriate battery storage assumptions.
4. DESC did not include demand side management ("DSM") or purchased power as full resource options available to add to candidate resource plans.
5. DESC did not systematically compare resource options for meeting its peaking reserve margin increment.

Overall, I conclude that DESC's IRP fails to comply with Act 62 standards for designing candidate resource plans. I recommend modeling corrections to the 2020 IRP and further improvements for the 2021 IRP to address these issues.

Q. WHAT IS A CANDIDATE RESOURCE PLAN?

A candidate resource plan is a collection of resources that could be deployed to meet electric system needs. Candidate resource plans consist of a schedule of resource additions and retirements that specifies the type, amount, and timing for each resource to be deployed. IRPs typically compare several candidate resource plans in order to identify a preferred plan that will guide the utility's resource acquisition and related activities moving forward.

Evaluating the full range of options for meeting demand, and treating each option on an equal footing with the other options, is critical because if certain realistically available options are not given a chance to compete on a level playing field (or compete at all) in the resource plan analysis, then the best plan may be overlooked and customers would face higher costs and/or higher risks than necessary.

Q. WHAT REQUIREMENTS DOES ACT 62 SET FOR CANDIDATE RESOURCE PLANS?

Act 62 provides that each utility's IRP must contain "several resource portfolios developed with the purpose of fairly evaluating the range of demand-side, supply-side, storage, and other technologies and services available to meet the utility's service obligations."[12] Act 62 also requires "an analysis of the cost and reliability impacts of all reasonable options available to meet projected energy and capacity needs."[13] These requirements align well with industry best practices, which

[12] S.C. Code Ann. § 58-37-40(B)(1)(e).
[13] S.C. Code Ann. § 58-37-40(B)(1)(h).

emphasize consideration of "a full range of supply alternatives" with "reasonable assumptions about the costs, performance, and availability of each resource."[14]

Q. PLEASE DESCRIBE THE CANDIDATE RESOURCE PLANS EVALUATED IN DESC'S 2020 IRP.

DESC designed and evaluated eight candidate resource plans. The eight plans include different combinations of six supply-side resource types (including storage, solar PV, and gas technologies) plus several existing unit retirement options.[15] DESC created the candidate resource plans "by hand" -- manually choosing when and which existing resources would be retired, as well as when, which, and what size new resource additions (from the six potential resource options) would be added within each plan.[16]

Q. ARE THERE OTHER APPROACHES TO DESIGNING CANDIDATE RESOURCE PLANS?

Yes. A common approach to designing candidate resource plans is the use of a capacity expansion model.

Capacity expansion models are computer models that simulate generation and transmission capacity investment, given assumptions about future electricity demand, fuel prices, technology cost and performance, and policy and regulation. With capacity expansion modeling, the IRP process is not limited to considering a limited set of handpicked candidate resource plans. Instead, the utility can test every possible combination of resource deployment and retirements to determine which scenarios optimally meet the goals of the IRP process. Duke Energy Carolinas and Duke

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[14] R. Wilson & B. Biewald. Best Practices in Electric Utility Integrated Resource Planning. Regulatory Assistance Project (2013) at 30.
[15] DESC witness Neely direct testimony at 4-10.
[16] SBA Interrogatory 1.

Energy Progress use a capacity expansion model called System Optimizer to guide candidate resource plan design.[17]

The CRA Report discusses capacity expansion modeling but uses the analogous term "long-term capacity expansion" ("LTCE"), which it describes as "optimiz[ing] generation costs over time by making new build and retirement decisions." CRA explains that "[a]n LTCE process will maintain a utility's required reserve margin using the least-cost portfolio, given a list of available retirements and new resources."[18] According to CRA, "not utilizing a model with LTCE functionality limits the portfolio options to a pre-defined list with pre-determined addition and retirement years. LTCE optimization would likely provide added insight into the DESC portfolio as it relates to early retirement options, the impact of new resource timing, and varying combinations of new resources. An LTCE simultaneously tests all possible combinations of these factors under differing load, fuel, and policy environments which could potentially identify cost savings or portfolio risks which would otherwise not be apparent."[19] By testing every possible combination, LTCE models ensure that no potential resource plan is overlooked and not considered.

Q. DID DESC USE CAPACITY EXPANSION MODELING TO IDENTIFY CANDIDATE RESOURCE PLANS?

No. As discussed above, DESC manually selected its candidate resource plans rather than choose them systematically using capacity expansion modeling. As CRA explains in its report, PROSYM (the production cost modeling software used by DESC in its IRP) does not contain the capability to perform long-term capacity expansion modeling.[20] CRA suggests that in future IRPs, the utility

[17] DEC 2018 IRP at 81; DEP 2018 IRP at 79.
[18] CRA Report 58.
[19] Id.
[20] Id.

should "consider incorporating another tool that allows for least cost optimization of capacity expansion." In other words, DESC should use capacity expansion modeling in its IRPs.

Q. DID DESC OVERLOOK ANY POTENTIAL CANDIDATE RESOURCE PLANS?

Yes. For example, none of the candidate resource plans evaluated by DESC include any new resources added before the year 2026. Additionally, DESC did not consider any candidate resource plans with existing unit retirements prior to 2028.

Q. SHOULD THE COMMISSION BE CONCERNED ABOUT THESE OMISSIONS?

Yes. Resource plans featuring more accelerated coal retirements and/or near-term additions of clean energy resources such as solar PV may perform better than any of the eight candidate resource plans evaluated by DESC. In other words, a candidate resource plan with earlier clean energy additions, or earlier coal unit retirements, might save customers money and/or expose them to less risk than any of the plans considered by DESC. For example, last year Duke Energy Carolinas announced accelerated retirement of several coal units.[21] Consumers Energy is another example of a utility that has recently committed to early retirement of coal units, which the utility is replacing with solar PV, wind, and DSM.[22]

The CRA Report supports "incorporating another tool that allows for least cost optimization of capacity expansion" and consideration of "a broader assessment of existing resource options with fuller support for specific retirement dates evaluated."[23]

Q. DID SCSBA PROPOSE ADDITIONAL RESOURCE PLANS?

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[21] D. Sweeney. Duke Energy outlines early retirement of 5 North Carolina coal-fired generation units. S&P Global Platts (October 2019). https://www.spglobal.com/platts/en/market-insights/latest-news/coal/100119-duke-energy-outlines-early-retirement-of-5-north-carolina-coal-fired-generation-units

[22] Consumers Energy 2019 Clean Energy Plan, Executive Summary. https://www.consumersenergy.com/-/media/CE/Documents/sustainability/integrated-resource-plan-summary.ashx?la=en&hash=9F602E19FE385367FA25C66B6779532142CBD374

[23] CRA Report at 53

SCSBA had the opportunity to propose up to five resource plans that would be analyzed by DESC as part of the development of the 2020 IRP, pursuant to the settlement agreement between DESC and the SBA in docket 2017-370-E.[24] The SCSBA plans did include near-term deployment of solar as well as more accelerated coal retirements, but the tremendous range of possible plans within these broad categories of candidate resource plans wasn't possible to assess in just five plans. Additionally, SCSBA and other intervenors had almost no knowledge of DESC's analytical design, resource plans the Company planned to evaluate, or key data inputs such as load forecast at the time DESC requested the plans to be finalized. Without an open and cooperative exchange of information, the considerable value that stakeholder input can have[25] into the development of an IRP will not be realized.

Q. PLEASE DISCUSS HOW DESC COULD HAVE EXPLORED CLEAN ENERGY ADDITIONS AND ACCELERATED COAL RETIREMENTS.

The Company could have designed candidate resource plans that included, for example, additions of solar PV within the next several years. Coal retirements could also have been scheduled within the next several years in one or more candidate resource plans. There are many variations on these strategies that could be efficiently and comprehensively evaluated with a capacity expansion model. With or without such a model, the Company could have designed and evaluated representative examples of these types of candidate resource plans, to allow them to compete in the resource plan analysis.

Q. HAS DESC PERFORMED ANY RECENT ANALYSIS OF POTENTIAL COAL RETIREMENTS?

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[24] DESC describes the plans and presents their analytical results in 2020 IRP Appendix A.
[25] R. Wilson & B. Biewald. Best Practices in Electric Utility Integrated Resource Planning. Regulatory Assistance Project (2013) at 26.

Not in the last several years leading up to the development of the 2020 IRP. A comprehensive coal retirement analysis would provide valuable insights into IRP development. For instance, capacity expansion modeling could determine the optimal retirement schedules for maximizing ratepayer benefits. Even without capacity expansion modeling, other approaches that also use detailed modeling tools could be used to examine the economics of a wide range of retirement options. Such an analysis could also identify and evaluate additional considerations such as transmission system impacts and cost recovery implications. Duke Energy was recently ordered by the North Carolina Utilities Commission to perform a retirement analysis as part of an upcoming IRP:

> To address the issue of economic retirement of aging coal plants, in the 2020 IRPs DEC and DEP shall include an analysis that removes any assumption that their coal-fired generating units will remain in the resource portfolio until they are fully depreciated. Instead, the utilities shall model the continued operation of these plants under least cost principles, including by way of competition with alternative new resources. In this exercise the full costs of disposal of coal combustion wastes shall be included in making any comparison with alternative resources. If such analysis concludes that continued operation of the utilities' existing coal-fired units until they are fully depreciated is the least cost resource alternative, then the utilities 2020 IRPs shall separately model an alternative scenario premised on advanced retirement of one or more of such

units and shall include in that alternative scenario an analysis of the difference in cost from the base case and preferred case scenarios.[26]

Q. DO YOU HAVE ANY OTHER CONCERNS ABOUT DESC'S CANDIDATE RESOURCE PLANS?

Yes. My primary concerns are as follows:

1. DESC used unreasonable assumptions for solar PV and energy storage cost and system value in the candidate resource plans that include solar PV and energy storage.
2. DESC did not include certain available resources as potential resource options that could be included in candidate portfolios.
3. DESC designed its candidate resource plans to meet only its base reserve margin rather than its full peaking reserve margin.

Q. PLEASE EXPLAIN YOUR CONCERN ABOUT SOLAR PV ASSUMPTIONS.

Resource Plan 7 ("RP7") includes 400 MW of 20-year solar PPAs coming online in 2026. DESC assumed that the cost of these PPAs would be $49.05 / MWh[27], based on its adjusted version of the National Renewable Energy Laboratory ("NREL") Annual Technology Baseline ("ATB") medium price projections. But DESC's adjusted ATB price model is inconsistent with actual Southeastern solar PV market prices in recent years. For example, DESC's price model calculates a 20-year PPA price of $47.77 / MWh for a 2019 project.[28] By comparison, the 2019 North Carolina CPRE Tranche 1 average winning bid for a 20-year solar PPA was $38 / MWh – a difference of more than 20%.[29] And a 2019 RFI issued by Santee Cooper found a weighted average

[26] NCUC Docket E-100 Sub 157. Order Accepting Integrated Resource Plans and REPS Compliance Plans, Scheduling Oral Argument, and Requiring Additional Analyses (August 27, 2019) at 90.
[27] DESC Response to SBA Interrogatory 12
[28] *Id.*
[29] Accion Group. Final Report of the Independent Administrator RE: DEC, DEP CPRE Tranche 1 (July 18, 2019) at 1.

levelized cost of less than $28 / MWh for 20-year solar PPAs.[30] The General Assembly subsequently authorized Santee Cooper to move forward with the procurement of up to 500 MW of solar PV based on the RFI results.[31] Further, executed PPAs under SCE&G avoided cost tariffs available in 2017 with blended rates of $34 / MWh have been filed with the Commission.

DESC also created an additional PPA price model based on the ATB low price projections as requested for use in the SBA resource plans submitted to DESC pursuant to the merger settlement. That model calculates a 20-year PPA price of $42.15 / MWh for 2019, which is closer to regional market prices although still high. As a result of these faulty assumptions, DESC significantly overestimates the cost of solar PV relative to other potential resources.

The CRA Report discusses another important assumption within these PPA pricing models related to the federal solar Investment Tax Credit ("ITC"). "CRA believes that DESC may also have been conservative in its ITC assumptions for PPAs; DESC has assumed that full ITC qualification ends in 2019, and the ITC steps down to 10% from 2020-2022….Despite the ITC stepdown starting after 2019, developers can safe harbor ITC for up to four years if they incur at least five percent of the project costs in that year and receive the full ITC for that year. So for example, a project safe harbored in 2019 could enter into service in 2023 and still receive a 30% ITC."[32] In place of DESC's conservative safe harbor assumption, a reasonable assumption to make is that project developers are able to safe harbor the 22% ITC available in 2021. Even this assumption is conservative given there is still time in 2020 to safe harbor the currently available 26% ITC.

[30] nFront Consulting. Summary of Initial Assessment of RFI Submittals (November 2019) at 2.
[31] South Carolina Act No. 135 of 2020, Section 11(E)(2)
[32] CRA Report at 60.

For the purposes of DESC's 2020 IRP, the most reasonable solar PPA price curve to use is DESC's ATB low case adjusted to safe harbor the 22% ITC. As an illustration of the impact of using this input assumption, the 2026 PPA price in that adjusted low case is $36.19 per MWh, or approximately $13 per MWh lower than assumed for the RP7 modeling run. The inflated PPA price assumption used by DESC equates to an extra cost of $10.7 million per year during each year of the 20-year PPAs within RP7.

Q. WHAT OTHER CONCERNS DO YOU HAVE ABOUT DESC'S SOLAR PV ASSUMPTIONS?

DESC assumed that incremental solar PV has zero winter capacity value[33]. The PSC has ruled recently on this assumption, and has rejected it. Instead, in Order 2020-244 the PSC adopted an 11.8% capacity value for solar PV that recognizes a modest year-round capacity value for incremental solar on the DESC system.[34] The Company's erroneous assumption of zero capacity value has the effect of increasing the total cost of candidate resource plans that include solar, such as RP7. A reasonable assumption for the 2020 IRP is that solar PV has a capacity value equivalent to the ELCC specific to the system penetration level of incremental solar PV. That assumption would be consistent with Order 2020-244 but would apply any updates to the amount of solar PV on the system since the order so that the ELCC is representative of the capacity value of incremental solar at this point in time.

Q. PLEASE EXPLAIN YOUR CONCERN ABOUT DESC'S STORAGE ASSUMPTIONS.

RP7 also includes 100 MW of Company-owned 4-hour duration battery storage coming online in 2026. DESC assumed that the cost of this storage would be based on a capital cost of $1,645 per

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[33] SBA Interrogatory 12

[34] SCPSC order 2020-244 at 9-11.

kW.[35] However, similar to DESC's solar PV cost assumptions, these storage cost assumptions are inconsistent with market prices. The Santee Cooper RFI included indicative prices for adding storage capability to solar PPAs, including two proposals for 4-hour duration batteries. These projects submitted commercial online dates of 2022 and 2023, with costs of $1,324 per kW and $1,316 per kW, respectively.[36] These cost figures represent capital costs, financing, and operating costs on a present value basis. By comparison, DESC's assumed capital costs alone for 2022 and 2023 are $1,818 per kW and $1,773 per kW, respectively. This comparison illustrates that DESC's storage cost assumptions are unreasonably high, thereby inflating the total modeled cost of candidate resource plans with battery storage additions, such as RP7.

A reasonable set of storage cost assumptions would align with the market prices indicated by the Santee Cooper RFI. DESC's levelized cost of energy calculations for battery storage can be adjusted to use the NREL ATB's medium storage cost case (including capital and fixed O&M costs), and to make the same 22% ITC safe harbor assumptions discussed above for solar PV. This adjusted storage pricing model represents the cost of the storage portion of a solar plus storage PPA, and is comparable with (though higher than) market prices based on the Santee Cooper RFI.

Additionally, it is worth noting that several CPRE Tranche 1 winning bids include storage capability, which underscores the economic viability of solar plus storage PPAs.[37]

Q. PLEASE ELABORATE ON YOUR CONCERN ABOUT POTENTIAL RESOURCE OPTIONS.

First, demand-side management ("DSM") was not included as a full resource option that could be incorporated into candidate resource plans for evaluation across scenarios. Instead, DESC

[35] CRA Report at 61.
[36] nFront Consulting. Summary of Initial Assessment of RFI Submittals (November 2019) at 3.
[37] Accion Group. Final Report of the Independent Administrator RE: DEC, DEP CPRE Tranche 1 (July 18, 2019).

performed a DSM sensitivity whereby the costs of the eight candidate resource plans were calculated within one scenario (base gas, \$0 CO_2) with different levels of DSM. Thus, DSM was not fully evaluated because it was not modeled across all gas and CO_2 price scenarios. Act 62 specifies that IRPs "must include an evaluation of low, medium, and high cases for the adoption of renewable energy and cogeneration, energy efficiency, and demand response measures, including consideration of…. sensitivity analyses related to fuel costs, environmental regulations, and other uncertainties or risks."[38] And industry best practices for considering DSM within IRPs include creating DSM supply curves that identify specific quantities of DSM and their costs, which are then allowed to compete against supply-side resources within the cost modeling.[39]

Second, power purchases were not considered as a full resource option that could be incorporated into candidate resource plans for evaluation across scenarios. Off-system power imports are an available means of meeting capacity and energy needs and could play a role in a reasonable and prudent resource plan. Many utilities import power for multiple years or on a long-term basis as part of their generation mix. SCSBA plan 3 illustrates how capacity purchases could potentially be used as a low-cost "bridge" to enable accelerated coal retirement before taking advantage of expected continued declines in battery storage costs.[40]

Q. PLEASE EXPLAIN YOUR CONCERN ABOUT THE RESERVE MARGIN TARGET OF DESC'S CANDIDATE RESOURCE PLANS.

DESC uses its base reserve margin targets of 12% summer, 14% winter instead of its peaking reserve margin targets (14% summer, 21% winter) when constructing its candidate resource plans. The Company then supplements each candidate resource plan with short-term power purchases in

[38] S.C. Code Ann. § 58-37-40(B)(1)(e)
[39] R. Wilson & B. Biewald. Best Practices in Electric Utility Integrated Resource Planning. Regulatory Assistance Project (2013) at 24, 28-29.
[40] DESC IRP at Appendix A-2.

order to reach the full peaking reserve margin targets.[41] This approach effectively excludes hundreds of MWs from the IRP process where candidate resource plans are modeled and compared to one another. The PSC ruled on this issue previously and determined that the 21% peaking reserve margin was the appropriate target to use when setting avoided cost rates.[42]

The CRA Report determined that "DESC may also consider performing portfolio analysis against the full peaking reserve requirement in its future IRP in order to test whether such 'short-duration' resources [such as demand response, seasonal capacity purchases, peaking generator, and storage resources] are a cost-effective part of the portfolio, subject to other system and portfolio design constraints."[43]

Q. WHAT ARE YOUR CONCLUSIONS ABOUT DESC'S CANDIDATE RESOURCE PLANS?

They do not meet the requirements of Act 62 and do not align with IRP best practices. DESC's candidate resource plans overlook major possibilities for meeting energy and capacity needs, they include unreasonable assumptions about the cost and performance of solar and storage resources, they do not treat DSM resources fairly, they exclude power imports as a resource option, and they exclude a substantial amount of DESC's capacity need from competitive evaluation within the IRP. Overall, the candidate resource plans modeled by DESC do not fairly evaluate the range of technologies and services available to meet DESC's service obligations, and they do not analyze the cost and reliability impacts of all reasonable options to meet system needs.

Q. WHAT ARE YOUR RECOMMENDATIONS RELATED TO DESC'S CANDIDATE RESOURCE PLANS?

[41] DESC witness Neely direct testimony at 7.
[42] SCPSC Order 2019-847 at 22 and 50.
[43] CRA Report at 49

I recommend that the PSC require DESC to re-run its modeling of RP7 to address the issues I have raised, and I also recommend that several improvements to DESC's planning process be implemented for the 2021 IRP:

1. RP7 should be modified to include near-term clean energy additions and to use appropriate cost and system value assumptions, as I will further detail later in my testimony;
2. DESC should be required to use capacity expansion modeling in developing its 2021 IRP, and the Commission should solicit parties' recommendations on guidelines for incorporating this modeling tool into the 2021 IRP and approve a set of guidelines prior to DESC's 2021 IRP development process;
3. DESC should be required to perform a comprehensive coal retirement analysis to inform development of its 2021 IRP, and the Commission should solicit parties' recommendations on guidelines for performing this analysis and approve a set of guidelines prior to DESC's 2021 IRP development process;
4. For its 2021 IRP, DESC should be required to include DSM and purchased power as resource options that are incorporated into candidate resource plans and evaluated across multiple scenarios;
5. For its 2021 IRP, DESC should be required to build candidate resource plans to meet its full peaking reserve margin target, and the resource plan analysis should determine what type of resources best meet the peaking increment.

III. SCENARIO ANALYSIS

Q. PLEASE PROVIDE A SYNOPSIS OF YOUR TESTIMONY REGARDING DESC'S SCENARIO ANALYSIS.

Scenario analysis provides crucial information on how candidate resource plans perform under various possible future conditions. In this section, I discuss the following key issues with DESC's scenario analysis:

1. DESC's scenario analysis as designed does not consider a wide range of possible load conditions, gas prices, or CO2 prices.
2. DESC's scenario analysis fails to meet the Act 62 standard of testing candidate resource plans under various reasonable scenarios.

I also recommend improvements to the design and inputs of the scenario analysis for the 2021 IRP.

Q. WHAT IS SCENARIO ANALYSIS?

The future is uncertain, and many electric industry experts maintain that uncertainty in this sector is at an all-time high. For example, a recent publication by Lawrence Berkeley National Laboratory states that "Over the next two decades, the electricity industry will face uncertainty that is unprecedented both in its scale and scope."[44] In order to successfully navigate this decision-making environment, IRP must consider that uncertainty in a comprehensive manner and apply the findings when selecting a prudent long-term plan. Scenario analysis is the process of modeling the performance of each candidate resource plan under a variety of future conditions. The modeling results are then used to select the most reasonable and prudent plan at that time.

Thus, designing scenario and sensitivity analyses to capture the uncertainties facing the utility and its customers is a crucial task within resource planning. If scenarios and sensitivities are poorly designed, then IRP modeling results will not be representative of the possible futures that may unfold. Results that are not representative of those possible futures in turn create a danger of

[44] F. Kahrl et al., The Future of Electricity Resource Planning. Lawrence Berkeley National Laboratory (2016) at 72.

selecting a resource plan that does not align with decision-maker cost and risk preferences and that leads to bad outcomes for customers and/or the utility.

Q. WHAT ARE THE ACT 62 REQUIREMENTS FOR SCENARIO ANALYSIS?

Act 62 specifies that IRPs must include consideration of future load and proposed generation facilities "under various reasonable scenarios." IRPs must also include multiple resource portfolios evaluated under "sensitivity analyses related to fuel costs, environmental regulations, and other uncertainties or risks." Thus Act 62 specifically requires modeling of various load forecasts, fuel costs, and environmental regulations, but also includes an open-ended reference to additional uncertainties or risks. The Act also specifies the use of "reasonable scenarios."

Best practices for designing reasonable scenarios is summed up by the Brattle Group's recommendation to "Construct a range of plausible, internally consistent scenarios that characterize the range of uncertainty," with an emphasis on "explicit consideration of the wide range of uncertainty" facing the industry.[45] A National Regulatory Research Institute publication underscores this concept, questioning whether electric utility planning that considers "only a small range of expected outcomes and ignores the unexpected" can adequately capture today's uncertainties.[46]

Q. PLEASE DESCRIBE THE SCENARIO ANALYSIS PERFORMED DURING DEVELOPMENT OF DESC'S 2020 IRP.

DESC modeled each of the eight candidate resource plans under six scenarios. The six scenarios covered combinations of three different gas price projections and two different CO2 price

[45] M. Chupka et al., Reviving Integrated Resource Planning for Electric Utilities (The Brattle Group, 2008) at 2.
[46] D. Boonin. Utility Scenario Planning: "Always Acceptable" vs. the "Optimal" Solution (NRRI 2011).

projections, all assuming medium DSM. Separately, DESC modeled each of the eight candidate resource plans with low DSM and high DSM cases, both assuming base gas prices and \$0 CO2.[47]

Q. WHAT CONCERNS DO YOU HAVE ABOUT DESC'S SCENARIO ANALYSIS?

I have several concerns about DESC's scenario analysis:

1. Candidate resource plans were not tested for cost impacts of load diverging from the base forecast, and the range of load forecasts developed is overly narrow;
2. DESC's gas price sensitivity assumptions are skewed low;
3. The range of DESC's CO2 sensitivity assumptions is overly narrow.

Each of these issues skews the cost results, creating a misleading dataset for selecting the preferred plan.

Q. PLEASE ELABORATE ON YOUR CONCERN ABOUT THE LOAD FORECAST SENSITIVITIES.

I have two concerns about DESC's load forecast sensitivities. First, the range of the forecasts is too narrow and thus does not represent a wide but plausible set of potential future load conditions. CRA "notes that future IRPs could be enhanced by considering lower probability load outcomes that range further from the Base case outlook."[48] Second, DESC does not actually use its load forecast sensitivities in its cost modeling analysis. Instead, DESC only uses its base load forecast within its cost modeling[49], thus providing no information about how different resource plans are able to adapt to load conditions that diverge from the base forecast. DESC maintains that its low and high DSM cases serve as modeling load sensitivities,[50] but in addition to the best practice of treating DSM as a resource rather than a sensitivity case (discussed above), DSM impacts on load

[47] DESC witness Neely direct testimony at 11-13.
[48] CRA Report at 39
[49] SBA Interrogatory 10.
[50] SBA Interrogatory 10.

are not interchangeable with various load growth possibilities driven by factors such as economic growth and customer consumption patterns.

DESC's IRPs should quantitatively assess how different resource plans perform when load conditions shift, so that this information can be considered when selecting a reasonable and prudent plan. For example, PacifiCorp's resource plan analysis illustrates how load sensitivities can be modeled to determine how a resource plan would change if load diverged from the base forecast, as well as the cost impacts of those changes. Additionally, PacifiCorp creates a "resource acquisition path" that identifies "economic, load, reliability, and environmental policy trigger events that would require alternative resource acquisition strategies," and details how procurement activities would change in both the near-term and long-term to match the new conditions.[51]

Generally, resources that can be economically procured in smaller increments and that have shorter procurement lead times, such as solar PV and DSM, are well-suited to enhancing the adaptability of a resource plan to load forecast shifts.

Q. PLEASE ELABORATE ON YOUR CONCERN ABOUT GAS PRICE SENSITIVITIES.

DESC's natural gas price sensitivities are skewed towards lower pricing assumptions, and do not represent a wide but plausible set of potential gas prices. This shortcoming stems from DESC's approach to creating gas price forecasts, which uses simple, and in some cases arbitrary, compound annual growth rate assumptions applied to current prices. In other words, DESC has not utilized detailed modeling of supply and demand for natural gas and related markets to derive price forecasts. The Brattle Group notes that "Constructing realistic [fuel price] scenarios requires

[51] Pacificorp 2019 IRP, Volume I at 263 and 289.

considering current futures market data, U.S. and global fundamentals, and the relationship between fuel prices and climate policy."[52]

The US DOE uses a model called NEMS to simulate the US energy system and create the widely recognized Annual Energy Outlook. NEMS is a complex but transparent model[53] that comprehensively represents energy production and consumption to forecast energy, economic, and environmental outcomes, including fuel prices, under a range of assumptions about the future. "The primary fuel supply and conversion modules compute the levels of domestic production, imports, transportation costs, and fuel prices that are needed to meet domestic and export demands for energy, subject to resource base characteristics, industry infrastructure and technology, and world market conditions. The modules interact to solve for the economic supply and demand balance for each fuel."[54] Given this detailed modeling of supply and demand, NEMS is an ideal source of Henry Hub gas price projections. Absent a comparable modeling platform for projecting fuel prices and a compelling case for why such a platform creates superior projections, the NEMS base, low, and high gas price projections constitute a reasonable set of gas prices that are wide ranging but also plausible given they are derived from detailed modeling of supply and demand. I do agree it is reasonable to use one year of natural gas futures prices to begin the price projections, given that AEO is only published once per year and thereby cannot update its results based on month to month movements in gas prices and other relevant data.

Figure 2: AEO versus DESC natural gas price projections

[52] M. Chupka et al., Reviving Integrated Resource Planning for Electric Utilities (The Brattle Group, 2008).
[53] The DOE website includes hundreds of pages of documentation on NEMS structure and function: https://www.eia.gov/outlooks/aeo/nems/documentation/
[54] US EIA. The National Energy Modeling System: An Overview 2018. US Department of Energy (2019) at 10.

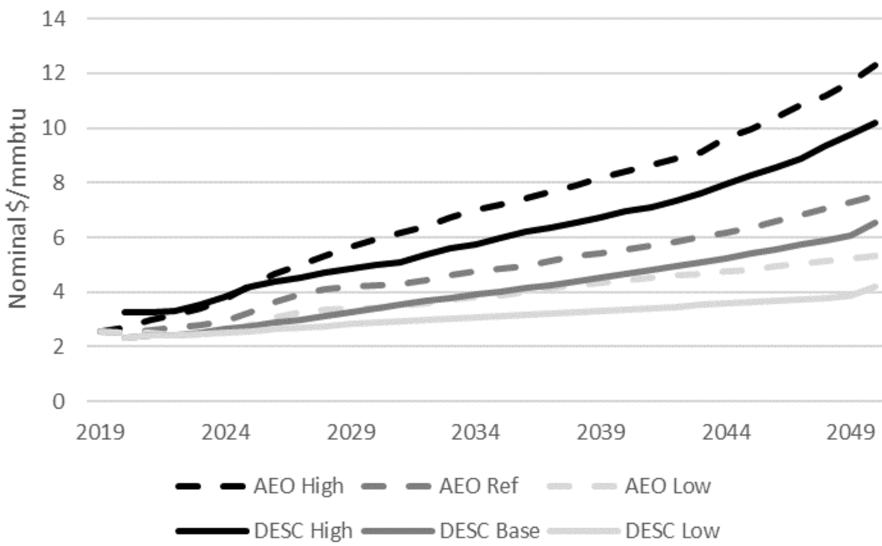


Figure 2 illustrates the stark difference in the AEO and DESC price projections. On average, the AEO prices are 19% higher than DESC's in the base case, 14% higher in the high case, and 23% higher in the low case. These price differences have very large impacts on production costs and overall candidate resource plan cost results across the scenarios, with lower gas price assumptions favoring gas-fired resources.

Q. DOES THE CRA REPORT DISCUSS DESC'S GAS PRICE PROJECTIONS?

Yes. The CRA Report concludes that "Given the consistent downward revision of the [AEO] Reference case Henry Hub forecast and the current low price environment, the Base case forecast used in the 2020 IRP is reasonable" and that for the same reason, DESC's high case, which CRA judges as "materially higher" than its base case, is also reasonable.[55] CRA does not comment on DESC's low gas projection. CRA also does not address DESC's lack of supply and demand modeling in general, or its failure to include wide-ranging projections while still ensuring those projections are plausible based on supply-demand modeling.

[55] CRA Report at 71

CRA's logic supporting a downward shift of base case prices also assumes judgments about the likelihood of the different scenarios into the formulation of the scenarios, which would bias interpretation of the final candidate resource plan cost results. It is possible that gas prices might trend lower than the AEO reference case, if certain variables change from current trends, and AEO does test cases where key assumptions are altered, which results in multiple lower price cases. Rather than arbitrarily lowering a reference case price curve that was derived from detailed supply-demand modeling, the appropriate approach to capturing the possibility of lower gas prices is to include a separate low gas price scenario.

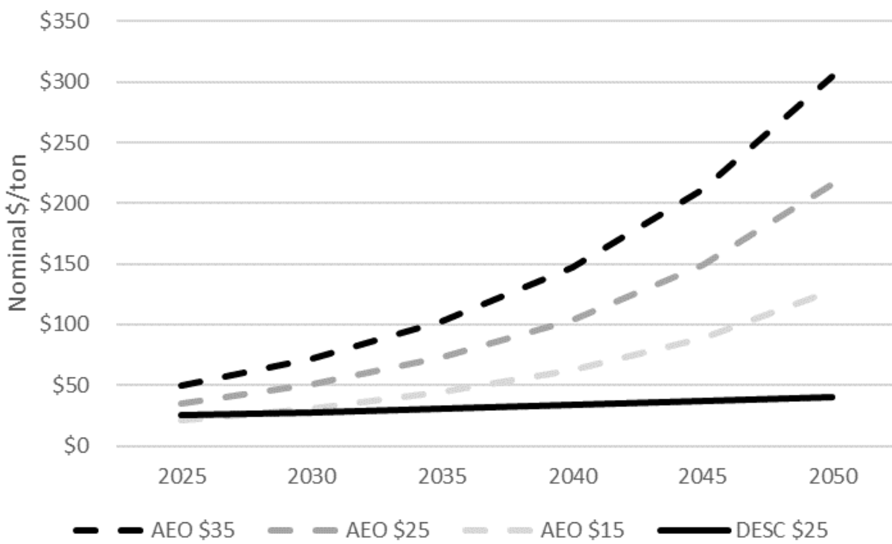
In summary, all three of DESC gas price projections are inappropriately skewed low when compared to a widely respected, detailed, and transparent supply-demand model.

Q. PLEASE ELABORATE ON YOUR CONCERN ABOUT CO2 PRICE SENSITIVITIES.

My concern about DESC's CO2 price sensitivities is similar to my concern about DESC's gas price projections: DESC does not model a wide but plausible set of potential CO2 prices. Figure 3 compares DESC's CO2 price case with the three CO2 price cases modeled in AEO2020. While AEO assumes a zero CO2 price in its reference case, it models three different potential CO2 prices, where even the lowest AEO price is substantially higher than that modeled by DESC. And in the AEO2020 high CO2 price case, by 2035 the price is $103 per ton, or more than three times the CO2 price in that year in the DESC CO2 price case. Notably, BP has now adopted an assumed carbon price of $100 per ton by 2030 in its investment planning.[56]

[56] J. Parnell. BP Adopts $100 Carbon Price Assumption for 2030, With Big Implications for Clean Energy (Greentech Media, June 16 2020). https://www.greentechmedia.com/articles/read/european-oil-majors-ready-to-scale-up-energy-transition-investment

Figure 3: AEO versus DESC CO2 price projections



The AEO modeling finds that under the high CO2 case, the fuel cost for coal generators increases from a current $21 / MWh to $75 / MWh by 2030[57], illustrating the cost impacts a CO2 price can have on fossil-fired resources and the importance of capturing realistic possibilities for GHG policy in the resource plan analysis.

Q. DOES THE CRA REPORT DISCUSS DESC'S CO2 PRICE PROJECTIONS?

Yes. The CRA report supports modeling scenarios with CO2 prices, and does not comment on DESC's pricing assumptions except to compare them to several Southeastern utilities and note that DESC's assumptions are within the range considered by those utilities.[58] Yet two out of the four utilities CRA cites model a high CO2 price that reaches $75 by 2035 and $180 by 2050. Further, Southeastern utilities have no special knowledge of what CO2 prices could be put into place, and review should not be arbitrarily limited to exclude other sophisticated entities with well-informed views of potential carbon pricing.

[57] Costs in 2019$. EIA. AEO 2020 Alternative policies – carbon fees documentation at 21 (DOE, March 2020).
[58] CRA Report at 72-73

Q. WHAT ARE YOUR CONCLUSIONS ABOUT DESC'S SCENARIO ANALYSIS?

DESC's scenario analysis does not comply with Act 62 or align with best practices. The load sensitivity approach does not provide information about the adaptability of the candidate resource plans to shifting load conditions, and the load forecast sensitivities are inappropriately narrow. The gas price and CO2 assumptions skew the results in a way that masks the full uncertainty and risk associated with fossil-fired resources. Overall, DESC's scenario analysis does not meet the standard of considering candidate resource plans "under various reasonable scenarios."

Q. WHAT ARE YOUR RECOMMENDATIONS RELATED TO DESC'S SCENARIO ANALYSIS?

I recommend that DESC be required to re-run its modeling with reasonable natural gas and CO2 price assumptions, and also that DESC be required to improve its scenario analysis for the development of the 2021 IRP, in the following ways:

1. Re-run the 2020 IRP modeling using the AEO low, reference, and high gas prices I have described, and using the AEO high CO2 case, as further detailed later in my testimony.
2. For the 2021 IRP, develop a wide but plausible range of load forecasts, and ensure that cost modeling captures each resource plan's capabilities to adapt to load that diverges from the base forecast.
3. For the 2021 IRP, use a wide but plausible range of gas price projections from AEO or another public, credible fundamental gas supply-demand model.
4. For the 2021 IRP, use wide but plausible zero/medium/high CO2 cost projections from AEO or other public sources.

<u>IV. SELECTING THE PREFERRED RESOURCE PLAN</u>

Q. PLEASE PROVIDE A SYNOPSIS OF YOUR TESTIMONY REGARDING DESC'S PREFERRED RESOURCE PLAN.

The preferred resource plan is the plan that will guide the utility's actions moving forward and shape a variety of related regulatory processes. In this section, I discuss the following issues relating to DESC's selection of its preferred resource plan:

1. DESC did not utilize a risk assessment in selecting its preferred resource plan, and thus did not adequately consider the Act 62 factors for identifying a reasonable and prudent plan.
2. I present a simple quantitative risk assessment and demonstrate its use in selecting a preferred resource plan.

In conclusion, I recommend an improved approach to selecting the preferred resource plan that complies with Act 62.

Q. WHAT IS A PREFERRED RESOURCE PLAN?

A preferred resource plan is the candidate resource plan that is selected, based on a comprehensive consideration of the IRP modeling results, to serve as the utility's plan moving forward. That plan will remain in effect until the next IRP proceeding, which updates and may alter the plan as appropriate. The preferred plan will also be used as an input to a variety of analyses in other dockets and regulatory processes, such as avoided costs, competitive procurement of solar and energy storage resources, new unit certification, DSM program planning, and many more.

Q. PLEASE DISCUSS THE SECTIONS OF ACT 62 RELATED TO SELECTING THE PREFERRED RESOURCE PLAN.

Act 62 directs the PSC to determine whether "the proposed integrated resource plan represents the most reasonable and prudent means of meeting the electrical utility's energy and capacity needs as of the time the plan is reviewed." The Commission must approve, modify, or deny the proposed plan based on a balancing of seven factors: resource adequacy, consumer affordability, environmental compliance, reliability, commodity price risk, diversity of generation supply, and any other factors in the public interest.[59]

Q. HOW DOES THIS STANDARD COMPARE TO INDUSTRY TRENDS AND BEST PRACTICES?

The Act 62 standard is in line with industry trends and best practices, which now have expanded resource plan assessment beyond a narrow least-cost approach to consider multiple evaluation factors, including risk.

For example, the Brattle Group maintains that evaluating plans across multiple dimensions "can provide policy makers with the kinds of information they need to identify preferred resource solutions in the face of large uncertainties. However, it is important to recognize from the start that it is unlikely that a single resource solution will be superior on every metric across all scenarios. Often a "robust second best" solution will present a more favorable value/risk profile than a solution that appears optimal in some scenarios (on some dimensions), but may perform poorly in others."[60]

LBNL notes that "The ability to undertake more systematic uncertainty and risk analysis has led to a gradual shift in focus in resource planning cost metrics, from an emphasis on "least-cost" to a growing emphasis on expected cost and cost variance" and identifies use of "risk-adjusted metrics" as one of "two key practices [that] will assist utilities and regulators to address the risks posed by rising uncertainty." Additionally, "The use of risk-adjusted metrics…provides a more rigorous approach to risk assessment than the more commonly used combination of

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[59] S.C. Code Ann. § 58-37-40(C).
[60] M. Chupka et al., Reviving Integrated Resource Planning for Electric Utilities (The Brattle Group, 2008) at 8.

scenarios and limited sensitivity analysis. If properly structured, the use of risk-adjusted metrics enables utilities, regulators and other stakeholders to identify investment and procurement strategies that have low costs and are robust across a large number of possible scenarios."

The approach used to select the preferred plan is another tremendously important aspect of resource planning. A poorly defined or inappropriate method of considering the results of the resource plan analysis and balancing multiple factors could lead to selection of a plan that doesn't align with the decision-makers' goals, and thereby raises customer costs or exposes customers to undue risk, and possibly exposes the utility to the risk of pressure to disallow cost recovery.

Q. PLEASE PROVIDE AN EXAMPLE OF A UTILITY THAT SEEKS A ROBUST PLAN AND/OR USES RISK-ADJUSTED METRICS.

Dominion Energy North Carolina performs a risk analysis using a probabilistic model that "runs many possible futures in hundreds of iterations" that are then "distilled into an expected levelized cost, a standard deviation, and an "upward" standard deviation to calculate the adverse cost risk to DENC's customers."[61]

TVA uses a probabilistic model to identify revenue requirement expected values, 5th and 95th percentiles, which results are then used to calculate risk metrics that inform plan evaluation.[62] The Kentucky Municipal Energy Agency describes their approach as follows: "Least regrets scenario planning requires selecting scenarios based on a range of plausible futures rather than the most likely case used in traditional least cost planning" with a goal of identifying a "portfolio that will perform well under different possible futures."[63] KYMEA's modeling process creates a probabilistic risk profile for each plan.

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[61] NCUC Docket No. E-100, Sub 157, Comments of the Public Staff at 38 (May 6 2020).
[62] TVA 2019 IRP Volume I, Chapter 6.
[63] KYMEA IRP Community Focus Group presentation at 7 (June 2020).

Q. WHICH PLAN DID DESC SELECT, AND HOW DID DESC SELECT THAT PLAN?

DESC selected RP2 as its preferred plan, by identifying RP2 as the least-cost plan under the base gas, \$0 CO2, medium DSM scenario based on the Company's modeling results. DESC reasons that this is the "most likely" scenario, but does not support that claim in any way, or even provide a basic explanation of how the Company identified the relative likelihood that a given scenario will unfold.[64]

To make matters worse, DESC's stated method of selecting the preferred plan does not actually use the results of five out of six scenarios that the Company modeled – that is, out of the 48 cost results for the eight candidate resource plans under six gas/CO2 scenarios, DESC's selection method only uses eight cost results to select its preferred plan, and ignores the other 40 results. DESC's selection method is illustrated in Table 1 below, where RP2 is identified as least cost under one scenario, ignoring most of the cost modeling results for purposes of plan selection.

Table 1: DESC Plan Selection Method (in \$1000)

		\$0 CO2			\$25 CO2	
	Low Gas	Base Gas	High Gas	Low Gas	Base Gas	High Gas
RP1	\$1,[redacted]528	\$1,249,160	\$1,[redacted]424	\$1,[redacted]375	\$1,[redacted]436	\$1,[redacted]590
RP2	\$1,[redacted]532	\$1,231,667	\$1,[redacted]354	\$1,[redacted]853	\$1,[redacted]736	\$1,[redacted]599
RP3	\$1,[redacted]235	\$1,251,077	\$1,[redacted]505	\$1,[redacted]378	\$1,[redacted]334	\$1,[redacted]688
RP4	\$1,[redacted]191	\$1,239,802	\$1,[redacted]558	\$1,[redacted]307	\$1,[redacted]231	\$1,[redacted]337
RP5	\$1,[redacted]034	\$1,266,727	\$1,[redacted]093	\$1,[redacted]516	\$1,[redacted]915	\$1,[redacted]182
RP6	\$1,[redacted]394	\$1,246,165	\$1,[redacted]590	\$1,[redacted]987	\$1,[redacted]797	\$1,[redacted]995
RP7	\$1,[redacted]889	\$1,236,518	\$1,[redacted]532	\$1,[redacted]024	\$1,[redacted]686	\$1,[redacted]813
RP8	\$1,[redacted]714	\$1,267,624	\$1,[redacted]499	\$1,[redacted]160	\$1,[redacted]706	\$1,[redacted]153

Q. DOES DESC'S PLAN ALIGN WITH ITS NET ZERO CORPORATE COMMITMENT?

[64] DESC Witness Bell direct testimony at 25.

No. DESC's preferred plan, RP2, continues to rely on coal- and gas-fired resources for the majority of its generation through 2050 and beyond. Even RP8, which the Company did not select but describes as its "low carbon plan,"[65] continues to rely on gas-fired resources for a large portion of generation through mid-century. In sum, DESC's preferred plan takes no steps towards reducing its greenhouse gas emissions, and DESC has not even designed a plan that could achieve Dominion Energy's net zero commitment.

Q. DO YOU AGREE WITH DESC'S PLAN SELECTION APPROACH?

No, I don't. DESC failed to fully consider and balance the Act 62 factors for identifying the most reasonable and prudent plan. In particular, DESC's selection approach does not adequately address uncertainty and does not consider commodity price risk or diversity of generation supply.

Q. HOW CAN UNCERTAINTY BE CONSIDERED AND THE ACT 62 FACTORS BE BALANCED?

Sophisticated risk-adjusted metrics cited as best practice and used by many utilities require specialized software and should be considered in the future. For this docket, there are relatively simple ways to capture uncertainty using traditional scenario analysis results.

One approach is to assess the cost spread for each resource plan across all scenarios.[66] This method reveals the forecasted range of costs that could be incurred under each plan, where a smaller cost range corresponds to less uncertainty about future electric system costs. Given that DESC modeled natural gas prices and CO2 prices, evaluating cost ranges using the DESC's modeling results provides a measure of commodity price risk.

[65] DESC 2020 IRP at 41.
[66] David Hoppock, Dalia Patino Echeverri, and Sarah Adair. 2013. Assessing the Risk of Utility Investments in a Least-Cost-Planning Framework. NI WP 13-07. Durham, NC: Duke University.

A second risk metric applicable here is regret scores. "Regret scores measure the difference in cost between the optimal solution for each scenario and the other investment options."[67] In other words, the least-cost resource plan under a given scenario would create no regrets in that scenario, whereas the other resource plans would result in regrets equal to the additional revenue requirements above those in the least-cost plan. Once the regret scores have been calculated for each scenario, a maximum regret score across all scenarios can be identified for each resource plan. Finally, the resource plan that "minimizes the maximum regret" is the least-risk option.[68] "Minimax regret analysis can identify the optimal blend of resources to create a diverse, resilient portfolio that ensures utilities do not rely too heavily on one resource over another."[69] Thus, regret scores are an appropriate risk metric for measuring diversity of generation supply.

Compared to DESC's plan selection method, cost ranges and minimax regret analysis both use all of the cost modeling results – that is, all 48 of the cost results shown in Table 1 rather than only 8 cost results – providing a systematic and objective methodology for considering the performance of each candidate resource plan under each scenario.

Q. PLEASE PROVIDE AN EXAMPLE OF A UTILITY THAT HAS USED SIMPLE RISK METRICS IN ITS IRPs.

Arizona Public Service uses the range of NPV revenue requirements and ranges of other metrics.[70] Consumers Energy also considers the range of NPV results.[71]

Q. HAVE YOU PERFORMED A COST SPREAD AND/OR MINIMAX REGRET ANALYSIS FOR DESC'S 2020 IRP?

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[67] Id.
[68] Patrick Bean & David Hoppock. 2013. Least-Risk Planning for Electric Utilities. NI WP 13-05. Durham, NC: Duke University.
[69] Id.
[70] APS 2017 IRP at 129.
[71] Consumers Energy 2018 IRP at 162.

Yes. In Table 2, I present the results of an analysis I performed to identify both the cost range of each resource plan and the maximum regret of each resource plan, using DESC's results from the Company's resource plan analysis.

Table 2: Risk metric values (in $1000) and ranks

	Range	Rank	Max Regret	Rank
RP1	$502,062	5	$30,730	4
RP2	$520,067	7	$23,030	2
RP3	$501,453	4	$30,973	5
RP4	$521,146	8	$31,525	6
RP5	$483,148	2	$40,502	7
RP6	$502,601	6	$27,091	3
RP7	$499,924	3	$16,980	1
RP8	$462,439	1	$53,967	8

Q. PLEASE EXPLAIN HOW YOU CALCULATED THE COST RANGES AND MAXIMUM REGRET VALUES.

The cost ranges are calculated by identifying the minimum and maximum costs of each plan across all scenarios, and subtracting the minimum from the maximum.

Table 3: Regrets table (in $1000)

	$0 CO2			$25 CO2			
	Low Gas	Base Gas	High Gas	Low Gas	Base Gas	High Gas	Max regret
RP1	$20,996	$17,493	$13,892	$29,215	$30,730	$22,437	$30,730
RP2	$0	$0	$2,822	$14,693	$23,030	$19,446	$23,030
RP3	$19,703	$19,410	$30,973	$16,218	$21,628	$20,535	$30,973
RP4	$8,659	$8,135	$12,026	$24,147	$31,525	$29,184	$31,525
RP5	$40,502	$35,060	$21,561	$38,356	$37,209	$23,029	$40,502
RP6	$17,862	$14,498	$10,058	$22,827	$27,091	$19,842	$27,091
RP7	$9,357	$4,851	$0	$13,864	$16,980	$8,660	$16,980
RP8	$38,182	$35,957	$53,967	$0	$0	$0	$53,967

Table 3 illustrates the regrets calculation, where the cost of the least-cost plan in each scenario is subtracted from the cost of each plan in that scenario. This reveals the $0 regret of choosing what turns out to be the least-cost plan in each scenario, as well as the dollar amount of regret for each other plan in that scenario. The regret scores for each resource plan are then compared to identify the maximum regret for each plan. For example, RP2 is identified as having no regrets in two of the scenarios, but has regrets in the other four scenarios, where other plans are least cost. The maximum regret across all six scenarios for RP2 is about $23 million. Thus, despite being least cost in the base gas, $0 CO2 scenario, RP2 is not the least regret plan based on DESC's cost results.

Q. PLEASE DISCUSS THE RESULTS OF YOUR ANALYSIS.

Across the six scenarios that DESC modeled, there is approximately $500 million levelized annual difference in costs, with some candidate resource plans forecasted as having a larger cost spread and some having a smaller cost spread. RP8 has the smallest cost spread across scenarios, at ~$462 million. RP4 has the largest cost spread at ~$521 million, and RP2 has a similar $520 million cost spread, making it the second largest of the eight plans evaluated. RP7 has the third smallest cost spread.

The minimax regret analysis reveals that RP7 is the least regrettable plan, or in other words the most diverse plan, with a maximum regret of about $17 million. RP2 is the second lowest regret plan at $23 million. RP8 has the highest regret score at $54 million.

Overall, considering the two risk metrics presented here based on DESC's cost results, RP7 is the most favorable resource plan. Further, these results are very likely muted by the flawed solar PV assumptions and the scenario design shortcomings discussed above – if those flaws were corrected, I would expect the risk assessment results to show similar rankings but with more magnified differences in values.

This result that RP7 reduces risk compared to RP2 is intuitive given DESC's current heavy reliance on coal- and gas-fired resources, which make up 26% and 45% of its generation, respectively.[72] Displacing several percentage points of fossil fuel generation with solar PV would remove a small portion of the risk associated with the overall portfolio.

Notably, RP8 has the smallest cost spread of any of the candidate resource plans, indicating less cost uncertainty than other options. The relatively high maximum regret seen for RP8 is likely reflective of the substantial amount of gas generation being substituted for the retiring coal plants. While RP8 overall has strong results, those results also suggest a need to model variations that include a more diverse substitute generation mix for retiring coal, as well as accelerated retirement dates and alternative unit retirement combinations.

Q. WHAT ABOUT THE OTHER FACTORS DESC MUST CONSIDER UNDER ACT 62?

In addition to the factors already discussed, the other factors that Act 62 requires the Commission to consider are: (1) resource adequacy, (2) consumer affordability, (3) environmental compliance, (4) reliability, and (5) any other "foreseeable conditions" that the Commission determines to be for the public interest.[73] Resource adequacy and reliability are ensured by building the candidate resource plans to meet the Company's target reserve margin. While I have not performed a detailed environmental compliance review, I am not aware of environmental compliance issues with the candidate resource plans. I am also not proposing any additional factors in the public interest at this time; however, I would like to highlight the possibility of modeling and considering public interest benefits such as health benefits of certain strategies, namely low-carbon resource plans. For example, a 2019 report on DEC and DEP found that a low-carbon resource plan would

[72] DESC 2020 IRP at 32.
[73] S.C. Code Ann. Sec. 58-37-40(C)(2).

substantially reduce lost work days and hospital admissions in the Carolinas, translating to hundreds of millions of dollars of annual benefits.[74]

Based on DESC's cost results, consumer affordability or "least cost" varies by scenario, which is a very common outcome in resource planning analyses. For example, out of DESC's six gas and CO2 price scenarios, RP2 is least cost in two scenarios, RP7 is least cost in one scenario, and RP8 is least cost in the other three scenarios. Thus, the cost results don't provide an obvious best choice from a least-cost standpoint.

Q. WHAT ARE YOUR CONCLUSIONS ABOUT DESC'S SELECTION OF ITS PREFERRED RESOURCE PLAN?

DESC's selection of RP2 as the preferred plan does not meet the Act 62 standard, because it doesn't address uncertainty and doesn't consider all seven of the Act 62 factors. My analysis incorporates simple, transparent metrics that measure commodity price risk and supply diversity. Using the Company's cost modeling results, those two factors differentiate the resource plans and reveal that RP7 outperforms the other plans. Thus, based on DESC's candidate resource plans and cost modeling results, RP7 provides the best balance among the Act 62 factors and would be the most reasonable and prudent plan at this time.

Later in my testimony, I will integrate this conclusion with my conclusions and recommendations on candidate resource plan design and scenario analysis.

Q. WHAT ARE YOUR RECOMMENDATIONS RELATED TO SELECTING THE PREFERRED RESOURCE PLAN ?

I recommend that the Commission reject DESC's approach of selecting the preferred plan based on a standard of least cost in a "base" or "most likely" scenario, and affirm the approach of

[74] R. Wilson et al., Modeling Clean Energy for South Carolina: An Alternative to Duke's Integrated Resource Plan (January 2019) at 8.

selecting the preferred plan based on a balancing of the Act 62 factors, including a systematic, quantitative assessment of commodity price risk and diversity of generation supply. I also recommend that the Commission initiate an exploration of approaches to risk assessment and management within IRP that can best satisfy Act 62 requirements, to include consideration of various risk metrics, risk modeling tools, and risk management strategies.

V. SYSTEM FLEXIBILITY

Q. PLEASE PROVIDE A SYNOPSIS OF YOUR TESTIMONY REGARDING SYSTEM FLEXIBILITY.

System flexibility has become an important consideration within power systems planning. In this section, I discuss the following points regarding system flexibility:

1. DESC has imposed invalidated system flexibility requirements in its 2020 IRP cost modeling, which inappropriately disadvantages plans that include solar PV.
2. DESC is considering system flexibility investments that would be added to customer rates, but has not assessed its system flexibility or compared different options for enhancing that flexibility.

I also make recommendations for reasonably representing system flexibility in the 2020 IRP, and for assessing and appropriately incorporating system flexibility into future IRPs and other regulatory processes.

Q. WHAT IS SYSTEM FLEXIBILITY?

System flexibility is the capability of balancing power supply and demand at all times.[75] All power systems must be flexible because "loads change over time and in sometimes unpredictable ways,

[75] Cochran et al., Flexibility in 21st Century Power Systems. National Renewable Energy Laboratory NREL/TP-6A20-61721 (2014).

and conventional resources fail unexpectedly." Renewable energy resources such as solar PV, like conventional resources, require system flexibility in order to operate normally.

System flexibility is now recognized as an important element to be considered within utility integrated resource planning. For example, a 2017 paper by the Brattle Group stated that:

> meeting the grid's increasing flexibility needs will require that utilities, system planners, policymakers, and market designers develop approaches that:
>
> • Better define flexibility needs to support reliability objectives;
>
> • Enable all existing resources that can provide flexibility to do so, whether in a regulated or market setting;
>
> • Attract suppliers who can provide innovative and cost-effective flexibility solutions.[76]

The paper also describes how traditional resource adequacy planning focused on meeting reserve margin targets, whereas today's advanced planning studies are adapting reliability assessments to include flexibility needs under various future conditions, identify latent flexibility uses of the existing grid, and facilitate ancillary services provision from any type of resource that can supply them.[77]

Q. DOES ENHANCED SYSTEM FLEXIBILITY BENEFIT CUSTOMERS?

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[76] Chang et al., Advancing Past "Baseload" to a Flexible Grid: How Grid Planners and Power Markets Are Better Defining System Needs to Achieve a Cost-Effective and Reliable Supply Mix. The Brattle Group (2017).
[77] Id.

Yes. System flexibility can reduce variable renewable resource curtailment and can reduce overall system costs and system emissions.[78]

A prominent example of these effects is the Western Energy Imbalance Market, where participants trade power with one another on a platform that "balances fluctuations in supply and demand by automatically finding lower-cost resources to meet real-time power needs." The EIM also "manages congestion on transmission lines to maintain grid reliability" and "makes excess renewable energy available to participating utilities at low cost rather than turning the generating units off."[79] In its six years of operation, the EIM has saved over $900 million for participants. Portland General Electric, for instance, which is a smaller utility like DESC, has saved $80 million since joining in late 2017.[80]

Q. HOW IS SYSTEM FLEXIBILITY IMPLICATED IN DESC'S 2020 IRP?

System flexibility is implicated in three major ways in DESC's 2020 IRP:

1. flexibility requirements imposed in its candidate resource plan modeling;
2. flexible operation mode assumptions for solar PV within candidate resource plans; and
3. statements about adding aeroderivative combustion turbines ("Aero CTs") to the system in the near term.

Q. PLEASE ELABORATE ON THE FLEXIBILITY REQUIREMENTS IN THE MODELING.

DESC imposes reserve requirements in its production cost model runs that are intended "to cover intermittent solar resources. Intermittent operating reserves modeled were 35% of solar nameplate

[78] Cochran et al., Flexibility in 21st Century Power Systems. National Renewable Energy Laboratory NREL/TP-6A20-61721 (2014) at 4.
[79] www.westerneim.com
[80] Id.

capacity during solar generating hours. Intermittent spinning reserves modeled were 35% of projected solar generation during solar generating hours." The basis provided for this assumption is the testimony of DESC witness Bell in Docket 2019-2-E and the testimony of DESC witness Tanner in Docket 2019-184-E including the Variable Integration Cost Study.[81]

The Commission has already ruled on this approach, and has rejected it.[82] Instead, the Commission adopted a flat $0.96 per MWh integration cost assumption for incremental solar PV.[83] That integration cost assumption was deemed to capture the flexibility requirements of solar PV such that the production cost modeling did not need to assume any additional reserves, beyond the baseline reserves, to cover solar intermittency. This remains a reasonable approach to use, especially for the modest incremental solar additions in candidate resource plans such as RP7, where the additional solar equates to only 3% of system sales. Additionally, the flexible solar operation assumption facilitates system balancing and thus would act to reduce the actual integration cost of these additions compared to the PURPA Qualifying Facilities ("QFs") under consideration in 2019-184-E.

The inappropriate flexibility requirement used by DESC affects the modeling of solar PV in the Company's candidate resource plans, including RP7. The use of this approach in docket 2019-184-E resulted in a decrease in solar PV value of $7-10 per MWh during the ten-year contract period modeled.[84] For illustrative purposes, substituting the approved $0.96 per MWh for the rejected $7-10 per MWh cost yields a difference of $5.9 million per year for the 400 MW of flexible solar generation in RP7.[85]

[81] SBA Interrogatory 18.
[82] SCPSC Order 2019-847 at 30, 42 and 56.
[83] SCPSC Order 2020-244 at 5.
[84] SCPSC Docket 2019-184-E, Independent Third Party Consultant Final Report at 6.
[85] Estimate uses the midpoint of the $7-10 per MWh range.

Q. PLEASE ELABORATE ON THE FLEXIBLE OPERATION MODE ASSUMPTIONS.

DESC assumes that all solar added in candidate resource plans is "flexible solar," which can be "dispatched down to zero megawatt (MW) and up to its forecasted generating capacity depending upon system conditions. Flexible solar can also provide up reserves during periods when it is not dispatched up to its full generation capability."[86] While I have not examined in detail how this designation impacts system operation and costs, this approach generally appears to be reasonable and would be expected to contribute to system flexibility. The Company also assumes that flexible solar PPAs would contract under a $/kW pricing structure,[87] which is also reasonable for this operating mode.

Q. HOW DOES THE IRP ADDRESS AERODERIVATIVE CTS?

The IRP discusses new peaking generation in several sections. For example, it states that "Reliable, fast-starting, and efficient peaking resources provide significant capabilities to balance intermittent renewable generation. Replacement of DESC's aging peaking generation resources with flexible aeroderivative-type combustion turbines is seen as a likely potential path to provide the flexibility to allow for further integration and additional expansion of intermittent renewable resources in the near-term."[88]

It is worth noting that DESC's preferred plan, RP2, as-modeled contains no new renewable resources for the next 40 years. Additionally, existing and under-contract renewable generation is already subject to the $0.96 per MWh charge recognizing additional operating reserves held with this generation on the system.

[86] SBA Interrogatory 13.
[87] SBA Interrogatory 12.
[88] IRP at 34.

Further, addition of Aero CTs in the near term was not included in any candidate resource portfolio modeled by DESC. Thus, by definition the resource plan analysis has not demonstrated that near-term addition of Aero CTs is part of the most reasonable and prudent plan.

Q. ARE AERODERIVATIVE CTS THE ONLY WAY TO ENHANCE SYSTEM FLEXIBILITY?

No. There are numerous ways to enhance system flexibility. A review of power system flexibility by the National Renewable Energy Laboratory highlights a substantial but non-exhaustive list of flexibility options, such as: [89]

- Grid codes
- Renewable energy forecasting
- Sub-hourly scheduling and dispatch
- Expanded balancing footprint / joint system operation
- Industrial and commercial demand response
- Residential demand response
- Hydro, coal, combustion turbine, and combined cycle ramping
- Advanced network management
- Transmission reinforcement
- Transmission expansion
- Thermal, pumped hydro, and chemical storage

The NREL authors also note that "Although options and associated costs to increase flexibility are very system-specific, in general tools that help access existing flexibility through

[89] Cochran et al., Flexibility in 21st Century Power Systems. National Renewable Energy Laboratory NREL/TP-6A20-61721 (2014) at 11.

changes to system operations and market designs are cheaper than those that require investments in new sources of flexibility."[90] Before implementing substantial flexibility measures, various flexibility options should be assessed as part of candidate resource plan cost modeling and comparison.

Q. ARE THERE ANY FLEXIBILITY OPTIONS THAT YOU WOULD LIKE TO HIGHLIGHT?

Yes. Expanded balancing footprint (the EIM is an example of this option), sub-hourly scheduling and dispatch, and renewable energy forecasting are examples of "changes to system operations" that NREL notes as low-cost flexibility enhancements. NREL also highlights industrial and commercial demand response as a relatively low-cost option. Battery storage costs have also declined considerably since this publication was released in 2014. And pumped hydro storage is another notable flexibility option given the large Fairfield pumped hydro facility on DESC's system. Finally, flexible solar operation is readily available with standalone solar PV projects. Each of these is a promising option for enhancing the Company's system flexibility, and many others may be viable and worth pursuing as well.

Q. HOW WOULD DESC DETERMINE WHEN, HOW MUCH, AND WHAT TYPES OF FLEXIBILITY SHOULD BE ADDED TO ITS SYSTEM?

Through independently validated, detailed assessment. While the Variable Integration Cost Study was an initial attempt, that assessment was overwhelmingly discredited by multiple parties to Docket 2019-184-E, with whom the Commission's consultant Power Advisory generally agreed, including a recommendation to re-evaluate the topic as part of the integration study authorized by

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[90] Cochran et al., Flexibility in 21st Century Power Systems. National Renewable Energy Laboratory NREL/TP-6A20-61721 (2014) at 11-12.

Act 62.[91] The study was also narrowly targeted to solar PV and the costs of holding a particular type of additional operating reserves using existing generating units, rather than taking a full-system approach that considers the flexibility of all system resources and a comprehensive suite of options for enhancing flexibility.

The NREL flexibility review highlights that "Many engineering-based flexibility tools and metrics have been developed in recent years and implemented in detailed power system studies. One example metric which might be implemented during system planning activities is Insufficient Ramping Resource Expectation (IRRE). This metric complements generation adequacy studies to assess whether planned capacity allows the system to respond to short-term changes in net load…. The value of IRRE is that the tool highlights time horizons of most risk, and measures the flexibility of the overall power system, not just the generation resources."

A recent Brattle Group presentation on resource planning commented that "properly decomposing system needs can more accurately compare the range of resources," illustrating this point with a comparison of the capabilities of various resources to provide specific types of ancillary services such as regulation, spinning and non-spinning reserves, and load following reserves, in addition to energy, capacity, and other capabilities.[92]

Q. PLEASE PROVIDE AN EXAMPLE OF A UTILITY THAT HAS INCORPORATED SYSTEM FLEXIBILITY ASSESSMENT INTO ITS IRP.

Public Service Company of Colorado has included a flexibility assessment in its IRP, which was cited as an example IRP best practice in a resource planning review paper.[93] PacifiCorp is another

[91] SCPSC Docket 2019-184-E, Independent Third Party Consultant Final Report at 6-25.
[92] K. Spees. The Cutting Edge of Resource Planning (Brattle Group, 2018) at 6.
[93] R. Wilson & B. Biewald. Best Practices in Electric Utility Integrated Resource Planning. Regulatory Assistance Project (2013) at 21.

utility that examines system flexibility within its IRP[94], including for example a detailed quantitative analysis of various reserves requirements as well as an assessment of the impacts of EIM participation on reserves needs. The flexibility analysis derives various inputs to PacifiCorp's overall IRP analysis.

Q. WHAT ARE YOUR CONCLUSIONS ABOUT THE TREATMENT OF SYSTEM FLEXIBILITY IN DESC'S IRP?

DESC has used a discredited and rejected approach to incorporating flexibility requirements within its production cost modeling runs that underpin its candidate resource plan cost estimates. Additionally, DESC has not adequately measured its system flexibility needs. These needs can be measured, just as capacity and energy needs are measured, and the full range of available options to meet those flexibility needs can be compared, either as part of candidate resource plans or otherwise where applicable.[95] Measuring system flexibility and evaluating options for system flexibility can in turn be incorporated into IRP, such that resource planning is able to achieve its intended purpose of systematically and fairly evaluating options for meeting customer demand.

Q. WHAT ARE YOUR RECOMMENDATIONS RELATED TO DESC'S SYSTEM FLEXIBILITY?

With regard to system flexibility, I recommend that the Commission take the following actions:

1. Reject the flexibility requirements incorporated into DESC's 2020 IRP cost modeling, consistent with previous orders;

[94] Pacificorp 2019 IRP, Volume II Appendix F.

[95] Potentially, certain flexibility options such as expanded balancing areas or improved renewable energy forecasting cannot be adequately represented or readily modeled within candidate resource plan cost analysis.

2. Direct DESC to use the $0.96 per MWh integration cost assumption to capture flexibility requirements for incremental solar PV at this time, consistent with previous orders;

3. Initiate the integration study authorized by Act 62, with a goal of completing the study in time for its findings and recommendations to be incorporated into DESC's 2021 avoided cost proposal. The integration study should cover the following topics:

a. Effect of various renewable penetration levels, from current levels to very high;
b. Impact of various renewable energy operating modes;
c. Impact of expanded balancing areas (such as an EIM platform or other means of joint system operation), sub-hourly scheduling and dispatch, and improved renewable energy forecasting;
d. Impact of industrial and commercial demand response;
e. Impact of battery storage;
f. Impact of pumped hydro storage;
g. Recommended methods for decomposing (*i.e.*, breaking out) and identifying system ancillary services needs;
h. Recommended metrics for system flexibility;
i. A comprehensive review of options for enhancing system flexibility, with generic cost estimates for each;
j. Discussion of the system flexibility needs and capabilities of conventional generation, including but not limited to impacts of coal retirement;

k. Recommendations for incorporating system flexibility into IRP; and

l. Recommendations for capturing system flexibility value within avoided cost tariffs.

VI. CONCLUSIONS AND RECOMMENDATIONS

Q. PLEASE PROVIDE YOUR OVERALL RECOMMENDATIONS FOR IDENTIFYING A REASONABLE AND PRUDENT PREFERRED RESOURCE PLAN FOR DESC'S 2020 IRP.

As discussed previously in my testimony, I recommend a limited, practical set of additional cost analyses that would allow the Commission to identify a reasonable and prudent resource plan, in compliance with Act 62. While a much more comprehensive re-working of DESC's IRP development would be ideal, my targeted recommendations identify analytical improvements that can achieve compliance with Act 62 within the statutory time constraints and at no cost.

I recommend that the Commission require DESC to:

1. Revise RP7 into two new candidate resource plans, as detailed below;
2. Correct the flexible solar PPA cost assumptions to the DESC ATB low case, adjusted to safe harbor the 22% ITC for four years;
3. Correct the flexible solar PPA capacity value assumptions to the appropriate current ELCC
4. For battery storage PPA cost assumptions, use the capital and fixed O&M costs from the ATB medium case, adjusted to safe harbor the 22% ITC for four years;
5. Correct the system flexibility requirements to the $0.96 per MWh recognized solar integration cost while eliminating the solar-specific operating reserve and spinning reserve requirements;

6. Use the AEO low, reference, and high gas prices I have described in place of DESC's low, base, and high gas prices, and use the AEO high CO2 case in place of DESC's $25 CO2 case, in the revised cost analysis;

7. Re-model the costs of RP2 as well as the revised RP7 plans, for comparison purposes;

8. Re-calculate the total 40-year levelized NPV revenue requirements results for RP2 and the revised RP7 plans;

9. Not make additional discretionary changes to the plans or calculations; and

10. File the cost modeling results with the PSC, including the 40-year levelized NPV revenue requirements for each of the three candidate resource plans identified in these recommendations, across each of the six gas-CO2 scenarios identified in these recommendations, and including the cost range and minimax regret scores and rankings as presented in my testimony.

The new calculations and results should be reviewed by the ORS, including a verification that DESC adjusted the expansion plans and calculations as directed and did not make any inappropriate additional changes. These new results would then serve as the basis for the Commission's consideration and balancing of the seven Act 62 factors, and selection of the most reasonable and prudent of the three candidate resource plans covered in the final analysis.

I recommend that the Commission reject DESC's approach of selecting the preferred plan based on a standard of least cost in a "base" or "most likely" scenario, and affirm the approach of selecting the preferred plan based on a balancing of the Act 62 factors, including a systematic, quantitative assessment of commodity price risk and diversity of generation supply.

Q. PLEASE PROVIDE THE REVISED RP7 PLANS TO BE RE-MODELED.

RP7-A should modify the original RP7 expansion plan by adding the 400 MW of flexible solar PPAs in 2023 instead of 2026, and by eliminating the battery storage addition entirely. The conventional CT additions to maintain the 14% base reserve margin and short-term power purchases to maintain the 21% peaking reserve margin should be adjusted appropriately to meet the reserve margin target at least cost.

RP7-B should modify the original RP7 expansion plan by adding the 400 MW of flexible solar PPAs in 2023 instead of 2026, and by adding the 100 MW battery storage in 2023 instead of 2026. The battery storage addition should be modeled as battery storage PPAs that are paired with solar PV and are thus able to utilize the federal ITC. The conventional CT additions to maintain the 14% base reserve margin and short-term power purchases to maintain the 21% peaking reserve margin should be adjusted appropriately to meet the reserve margin target at least cost.

Q. PLEASE COMPILE YOUR RECOMMENDATIONS THAT APPLY TO FUTURE IRPs AND OTHER MATTERS.

I recommend that the Commission enter an Order directing DESC to meet the following requirements in formulating its 2021 and later IRPs and IRP updates.:

1. DESC should be required to use capacity expansion modeling in developing its 2021 IRP, and the Commission should solicit parties' recommendations on guidelines for incorporating this modeling tool into the 2021 IRP and approve a set of guidelines prior to DESC's 2021 IRP development process;
2. DESC should be required to perform a comprehensive coal retirement analysis to inform development of its 2021 IRP, and the Commission should solicit parties' recommendations on guidelines for performing this analysis and approve a set of guidelines prior to DESC's 2021 IRP development process;

3. For its 2021 IRP, DESC should be required to include DSM and purchased power as resource options that are incorporated into candidate resource plans and evaluated across multiple scenarios;

4. For its 2021 IRP, DESC should be required to build candidate resource plans to meet its full peaking reserve margin target, and the resource plan analysis should determine what type of resources best meet the peaking increment;

5. For the 2021 IRP, DESC should be required to develop a wide but plausible range of load forecasts, and ensure that cost modeling captures each resource plan's capabilities to adapt to load that diverges from the base forecast;

6. For the 2021 IRP, DESC should be required to use a wide but plausible range of gas price projections from AEO or another public, credible fundamental gas supply-demand model;

7. For the 2021 IRP, DESC should be required to use wide but plausible zero/medium/high CO2 cost projections from AEO or other public sources;

8. The Commission should initiate an exploration of approaches to risk assessment and management within IRP that can best satisfy Act 62 requirements, to include consideration of various risk metrics, risk modeling tools, and risk management strategies;

9. The Commission should initiate the integration study authorized by Act 62, with a goal of completing the study in time for its findings and recommendations to be incorporated into DESC's 2021 avoided cost proposal. The integration study should cover the following topics:

a. Effect of various renewable penetration levels, from current levels to very high;

b. Impact of various renewable energy operating modes;

c. Impact of expanded balancing areas (such as an EIM platform or other means of joint system operation), sub-hourly scheduling and dispatch, and improved renewable energy forecasting;

d. Impact of industrial and commercial demand response;

e. Impact of battery storage;

f. Impact of pumped hydro storage;

g. Recommended methods for decomposing and identifying system ancillary services needs;

h. Recommended metrics for system flexibility;

i. A comprehensive review of options for enhancing system flexibility, with generic cost estimates for each;

j. Discussion of the system flexibility needs and capabilities of conventional generation, including but not limited to impacts of coal retirement;

k. Recommendations for incorporating system flexibility into IRP; and

l. Recommendations for capturing system flexibility value within avoided cost tariffs.

Q. PLEASE PROVIDE A SUMMARY AND CONCLUSION STATEMENT FOR YOUR TESTIMONY.

This proceeding is the first to occur under the overhauled integrated resource planning requirements of Act 62. Those requirements elevated the importance and rigor of IRP in South

Carolina, including a recognition that long-term plans for meeting customer demand must be made in an environment of enormous uncertainty. The SCGA through legislation has also expressed a clear and consistent goal of encouraging cost-effective clean energy growth across the state, and Dominion Energy has made a public commitment to achieving net zero GHG emissions by mid-century. The development of DESC's 2020 IRP was flawed in multiple major areas, as I have demonstrated, and neither the development of the IRP nor the selection of the proposed plan meets the standards of Act 62. My testimony has identified and recommended many improvements that should be applied to DESC's future IRPs, along with a targeted, pragmatic re-analysis plan that would reasonably cure the 2020 IRP's deficiencies within statutory time constraints. If RP7-A or RP7-B is judged to be the most reasonable and prudent plan according to the Act 62 criteria, the goals of the SCGA will be served, Dominion will continue to take tangible steps towards reaching its corporate commitments, and South Carolina will continue to see major investments and job creation in the clean energy sector at a time when this charge of economic development would carry an outsized benefit for South Carolinians.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

Yes it does.

Exhibit A

Kenneth Sercy *curriculum vitae*

Kenneth A. Sercy

kenneth@sercyconsulting.com

Summary

Electric power professional with advanced degree and 10 years' experience in electricity markets, policy, and regulation focused on power systems modeling and cost-of-service ratemaking.

Education

NARUC Utility Rate School
National Association of Regulatory Utility Commissioners and Michigan State University Institute of Public Utilities, Clearwater FL, October 2014

2013 Grid School
Michigan State University Institute of Public Utilities, Charleston SC, March 2013

Masters of Environmental Management, Energy & Environment concentration
Duke University Nicholas School of the Environment
Durham NC, May 2012

Key Coursework: Electric Power Markets, Energy Systems Modeling, Advanced Corporate Finance, Resource and Environmental Economics, Energy Technologies, Air Quality Management, Energy and Environmental Law, Energy Regulation and Policy, Modeling in the Earth Sciences with Matlab, Applied Data Analysis for Environmental Sciences

Bachelors of Science, Biological Sciences
Clemson University Calhoun Honors College
Clemson SC, August 2005

Skills

Electric power systems modeling – design, run, and evaluate a variety of electric power analyses including production cost, capacity expansion, and avoided cost and related cost-effectiveness tests

Cost-of-service utility ratemaking – evaluate cost recovery, asset certification, program and tariff design in context of ratemaking theory and practice

Technical communication – draft and edit legislation, regulatory testimony and comments, and technical reports; public speaking at internal and external meetings, technical committees, and conference speaking engagements

Software training and experience – Microsoft Excel (including Visual Basic), MathWorks Matlab, Microsoft Word, Microsoft Powerpoint

Experience

Independent Consultant
Denver CO, November 2018-present

- Primary client – major Southeast-based solar photovoltaic developer
- Provided strategic guidance, regulatory testimony and comment drafting and editing, and technical research relating to:
  - Avoided cost calculations and tariff design
  - Integrated resource planning
  - Renewable energy integration
  - Grid modernization
  - Green tariff design
  - Competitive wholesale power markets

Utility Regulation Specialist, South Carolina Coastal Conservation League
Columbia SC, June 2012-January 2018

- Conducted research and data analyses and drafted formal commentary and testimony for filing in sixty SC Public Service Commission electric utility proceedings relating to:
  - Integrated resource planning,
  - Demand-side management programs,
  - New generating unit certification,
  - Net energy metering and distributed energy resource programs
  - Interconnection standards
- Coordinated strategy for SC Public Service Commission proceedings with CCL Energy Director and partners at Southern Environmental Law Center and Southern Alliance for Clean Energy.
- Represented CCL in public and private meetings with electric utility staff, conservation partners, business representatives, state utility regulatory staff, other government staff, academic institutions, and media.

Research Assistant, Nicholas Institute for Environmental Policy Solutions
Durham NC, September 2010-May 2011; September 2011-April 2012

- Used a U.S. DOE energy-economic modeling tool (NEMS) to evaluate economic, environmental, and power system impacts of modeling assumptions regarding resource abundance, technological development, and policy choices.
- Conducted research and stakeholder outreach with universities and state agencies aimed at identifying and overcoming barriers to implementing modeled policies.

Policy Analyst Intern, North Carolina Sustainable Energy Association
Raleigh NC, May 2011-August 2011

- Analyzed state electricity rate changes based on North Carolina Utilities Commission dockets and co-authored white paper on drivers and economic impacts of utility resource decisions in North Carolina.
- Tracked proceedings of interest at North Carolina Utilities Commission, met with stakeholders, and supported NCSEA's intervention in Duke-Progress merger proceeding at NCUC.
- Compiled and maintained public database of current energy-related legislation at North Carolina General Assembly and supported NCSEA legislative lobbying efforts.

Copy Editor, Nature Chemical Biology, Nature Publishing Group
New York NY, March 2006-March 2010

- Edited journal content for consistency, logical flow, technical style, and grammar within fast-paced deadline schedule.

- Wrote summaries of research articles for In This Issue section of journal.
- Collaborated with authors, editors, and production staff to develop and update editorial policy, technical style, and internal workflow process.
- Trained new hires in editing standards and practices.

Publications

Sercy, K., Carey, R.T. & Saltzman, E.W. South Carolina Offshore Wind Economic Impact Study: Phase 2. Prepared for the South Carolina Energy Office (2014).

Sercy, K. A Modeling Tool for Fuel Price Risk Management in Power Generation Portfolio Planning. Master's Project, Duke University Nicholas School of the Environment (2012).

Brown, M.A., Gumeran, E., Sun, X., Sercy, K. & Kim, G. Myths and Facts about Electricity in the U.S. South. *Energy Policy* 40(1), 231-241 (2012).

Kennerly, J., Urlaub, I., O'Hara, B., Sercy, K. & Papazian, J. Understanding the Impact of Electric Generation Choices on North Carolina Residential Electricity Rates. North Carolina Sustainable Energy Association (2011).